RESTRUCTURED FUTUREGEN PRE-APPLICATION MEETING PUBLIC QUESTIONS/DOE RESPONSES

Q1 – Will DOE take ownership of the equipment purchased in part with the DOE cost share?
A1 – The Administration's Fiscal Year 2009 Budget Request seeks authority which would permit DOE to vest free and clear title to property in the recipient – similar to language applicable to the Clean Coal Power Initiative. If the authority is not granted, property rights will be determined in accordance with DOE's financial assistance regulations found at 10 CFR 600. Per the regulations, the recipient has legal title to recipient-acquired property that is acquired during the project. DOE has certain retained interests in the property which are defined in the regulations.

Q2 – The Announcement states, "Demonstration Project Operations are expected for 3-5 years and must capture and store in a saline formation at least one million metric tons of CO_2 per year during this time period. It is possible the first year may be less because of start-up, tuning, etc. Can the CO_2 capture and storage be averaged over the period of performance for the demonstration project? What happens if you don't meet the 1 million metric tons per year the first year?
A2 – DOE will require sequestration of CO_2 in a saline formation at an expected rate of 1 MMT/yr (FOA, p. 8, Primary Technical Goals and Functional Performance Requirements). Therefore, the project must be designed to achieve that goal. However, because the capture and sequestration requirement is stated in terms of a rate, it is not a violation of the terms of the FOA if the total injection into a saline reservoir does not amount to 1 MMT in any year. So, if the demonstration unit operates for only half of the year, despite best efforts, then only 0.5 million tons of CO_2 must be sequestered in a saline formation(s). Start-up and shake down problems during the first year, for example, could result in less than 1 MMT being sequestered.

Q3 – Is an abandoned gas, porous substrate an acceptable storage reservoir? It may not be used for natural gas recovery. If this is not acceptable, please describe an acceptable storage reservoir.
A3 – Generally, the answer is no. However, it is possible that an abandoned gas reservoir could be acceptable to DOE – if it is now the same as a saline formation. In other words, if all the natural gas was removed and brine moves into and now occupies the pore space, the reservoir would be the same as a saline formation. To be consistent with the objectives and intent of the FOA, if the abandoned gas reservoir might again produce economical quantities of natural gas after CO_2 is injected, the depleted reservoir does not qualify (the project will be considered to be an enhanced natural gas recovery effort, which is not within the intent of the goal). In such a case, the excess CO_2 (i.e., that CO_2 in excess of the 1MMT/yr to be sequestered in a saline formation) could be used and sequestered in the depleted reservoir. Even if a proposed abandoned gas reservoir does meet the definition and thereby qualify, it may get a lower score for technical merit because it would less convincingly demonstrate the wide-spread applicability of geologic sequestration – depleted natural gas reservoirs are not as broadly and abundantly

distributed across the U.S. as saline formations that never yielded economical quantities of natural gas.

The term “saline reservoir” will be defined in an amendment to the Funding Opportunity Announcement, but to allow interpretation of the above Question 3 and Answer 3 the proposed is offered:

*“Saline Formation” means a porous and permeable body of rock or sediment, (a) which has the capacity to safely store large quantities of carbon dioxide that would be captured from a fossil fueled energy conversion facility (power plant), (b) which is characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the Earth's surface or traceable in the subsurface, and (c) which does not meet the definition of an “underground source of drinking water”, as defined in 40 CFR Part 144.3 (**Underground** source of **drinking water** (USDW) means an aquifer or its portion:*

*(a)(1) Which supplies any public **water** system; or*

*(2) Which contains a sufficient quantity of ground **water** to supply a public **water** system; and*

*(i) Currently supplies **drinking water** for human consumption; or*

(ii) Contains fewer than 10,000 mg/l total dissolved solids; and

(b) Which is not an exempted aquifer).

Q4 – Can all operating costs, including fuel, be counted as cost share during the demonstration period? If not, can the incremental costs (i.e., higher operating costs) during the demonstration period be counted as cost share?

[The Announcement states on page 12, “…Because DOE is treating the costs (e.g., fuel) to produce electricity as an allowable cost for cost sharing purposes, a separate charge for power supplied to the sequestration component will not be allowed, nor will DOE share in costs associated with reduced or lost opportunity. Such costs will not be considered as cost-sharing.]

A4 – For greenfield projects, all operating costs, including fuel, can be counted as cost-sharing but only those additional operating costs that are associated with CCS and with achieving the other FutureGen objectives (e.g., lower sulfur, NOx, particulate and mercury emission levels) can be included in the incremental cost calculation used to determine the maximum amount of DOE contribution.

For retrofit projects, DOE will not consider operating costs of the existing facility as cost-sharing – except for additional operating costs that are associated with CCS and with achieving the other FutureGen objectives (e.g., lower sulfur, NOx, particulate and/or mercury emission levels). For retrofit projects, such operating costs can be included in the incremental cost calculation used to determine the maximum amount of DOE contribution.

Note that the FOA only recognizes coal as an allowable fuel cost and does recognize other fuels that may be required for start-up.

Q5 – Due to prevailing market volatility relative to fuel, transportation costs, and labor, will DOE disclose what it plans to use as reasonable cost escalation from 2008-2015? [The Announcement states on page 12, "…DOE is under no obligation to share any cost growth (i.e., costs incurred during the Demonstration Project that are more than estimated at the date of award.)
A5 - Future cost escalation is difficult to predict. The applicants will have to make their best estimate and present their underlying rationale in the applications. The cost estimate presented to DOE in the application should include projected escalation.

Q6 – Please provide insight on what DOE considers a "commercially viable size" for an advanced clean coal based power generation technology with Carbon Capture and Storage. For example, is 100MW not acceptable?
[Refer to page 8, "The Demonstration must be designed…for a non gasification project be at a commercially viable size."
A6 – The plant must be sized to produce at least 1 millions ton/year of CO_2 that can be sequestered in a saline formation. Other than that, the applicant should show that the demonstration scale is such that it does not need to be demonstrated at a greater size to be ready for sale into the commercial market.

Q7 – Do you still expect the selection announcement to be made according to the schedule in the announcement, i.e. December 2008?
A7 – Yes.

Q8 – As part of the Funding Plan (page 25) the applicant is asked to "identify the estimated annual budget for the source of funding to meet project development costs…including identification of sources and amounts of contingency funding for cost growth and overruns." Is contingency an allowable cost when estimating DOE's cost share contribution?
A8 – Contingency is not an allowable cost as such, but it can be used for estimating purposes such that it is consistent with generally accepted industry engineering practices.

Q9 – Can the "**budget periods**" be defined at this time?
The definition of the "Budget Period" means the interval of time, specified in the award, into which a project is divided for budgeting and funding purposes. Please identify the budget periods by time period, e.g. Budget Period 1: January 1, 2010 thru September 30, 2010 Budget Period 2: October 1, 2010 thru September 30, 2011, etc.

[Ref **APPENDICES/REFERENCE MATERIAL**
"Budget Period" means the interval of time, **specified in the award**, into which a project is divided for budgeting and funding purposes.

The Project Management Plan establishes the baseline for the scope, schedule, and budget for the project and shall include the information below. The Project Management Plan should be provided as Appendix C;

- A Work Breakdown Structure to at least three levels **identifying tasks to be performed under each Budget Period]**

A9 - Since no two projects are the same, there is no fixed time for budget periods. For projects such as these, an applicant may generally assume1-2 years for NEPA and preliminary design; 1-2 years for detailed design; 2-4 years for construction; 3-5 years for operation; and, 2 years for MMV. Applicants should propose budget periods appropriate for their projects bearing in mind the requirement for scheduled start-up by December 2015. If an applicant chooses to overlap design and construction, this budget period should be proposed at logical break points. DOE and the applicant will develop mutually acceptable budget periods after selection.

Q10 – Are subcontractors permitted to charge fee or profit?
A10 – Yes – if the subcontractors are not team members whose technology is being demonstrated or who otherwise have a financial interest in the outcome of the project. For example, subcontractors or vendors who are providing commercially available goods or services may be paid fee or profit.

Q11 – Do all of your questions and answers apply to both Cooperative Agreements and TIAs? If not, please explain or elaborate.
A11 – Most answers apply to both Cooperative Agreements and TIAs. Where there is a difference, however, it will be identified. .

Q12 – Is an extension of the bid due date possible?
A12 – DOE does not anticipate extending the due date.

Q13 – Will the project team be allowed to retain 'market value' of the stored CO_2 such as trading credits or proceeds from the sale of CO_2 for enhanced oil recover or enhanced gas recovery?
A13 – Revenue generated from the project during the project period, including revenue from the sale of CO_2 or CO_2 trading credits, would be considered program income. Per the FOA, program income may be used to finance the non-federal share of the project cost. After project completion, revenue generated from CO_2 credits or sale may be retained by the recipient with no obligation to DOE.

Q14 – Would the DOE consider a 2 month extension to proposal submission?
A14 – DOE does not anticipate extending the application due date.

Q15 – What types of "Alternative Technology" is DOE interested in seeing in upcoming proposals?
A15 –Alternatives to gasification technology may include combustion-based technology applications such as oxy-combustion or CCS retrofits to pulverized coal boilers.

Q16 – Schedule does not include phase in time to assess technology scale-up issues. Going directly to 81% on 300mw system is not fully developed.
A16 – FutureGen is targeting large scale projects that can achieve very high carbon reductions. Interested parties who do not believe they can achieve FutureGen goals may wish to consider DOE's CCPI Round III Funding Opportunity Announcement.

Q17 – Do the incremental costs include O&M, Increase Fuel and Replacement Power
A17 – For greenfield plants, the incremental cost calculation may include additional O&M and increased fuel due to CCS and other FutureGen emissions targets. Replacement power, lost opportunity or parasitic power is not considered an allowable cost since the cost of producing the power is considered in the cost-sharing base.

For retrofit applications, parasitic power for the CCS components and additional components necessary to meet FutureGen emissions goals can be considered in the incremental cost calculation. Such power may be charged to the project at production cost, rather than at lost-opportunity cost.

Q18 – Must we use a saline formation to sequester the CO_2? We utilize a more stable, permanent mineral sequestration process to capture CO_2. We can meet all other requirements of this RFP.
A18 – Restructured FutureGen (RFG) requires permanent sequestration of CO2 in geologic formations, including at least 1 million metric tons per year in saline formations (as defined in Q3 above). See FOA, p. 8, Primary Technical Goals and Functional Performance Requirements. Projects interested in mineral sequestration might consider CCPI-Round 3 as an alternative to the RFG geologic sequestration requirements.

Q19 – 2015-2020 indicates 3 yrs injection and 2 yrs monitoring. Are post-closure costs included in this FOA, i.e. dismantling, seal integrity, liability transfer?
A19 – Post-closure costs such as dismantling and disposal costs may be allowed, but only if they are proposed and contained in your application and if the dismantling and disposal occurs prior to completion of the cooperative agreement. DOE does not understand what is meant by "liability transfer." Generally, commercially available liability insurance would be an allowable project cost during the project. Post-project insurance or renewals would not be allowable.

Q20 – Is there interest in seeing FutureGen projects aligned with Regional Partnership Projects?
A20 – No – DOE is seeking single integrated projects for Restructured FutureGen. Furthermore, most Regional Partnership projects will have completed injection (or be nearing completion) ay by the time FutureGen projects enter operation. However, applicants may wish to draw on the extensive knowledge base developed by the Regional Partnerships to assist in their projects.

Q21 – Can the DOE provide guidelines on what inflation factor should be applied in financial models?
A21 – The applicants will have to make their best estimate for predicting future inflation, and present that best estimate along with its underlying rationale in the applications.

Q22 – Recommend adding "Information Technology" to evaluation criteria and weighted 10%. It is spread throughout SOW, e.g.:

- Project Management
- Cost Est CO_2 Mgmt Sys
- Monitoring Costs
- Funding Plan
- Financial Business Plan
- Scientific, Engineering, Technical, Scale-up
- Budget Development
- Monitoring NEPA Process
- Collaboration
- Configuration Mgmt

Examples of IT Reporting Future Gen:

- Maintenance and Inspection
- Tracking Federal & State Regulation
- Finance Modeling
- Identify & Analyze
- Record & Document Mgmts
- Public Outreach communication
- Costs Scheduling & Technical Performance & Measurement
- Health, Safety, Security
- Environmental Information & Impacts

A22 – We believe information technology capability is better evaluated in the context of the FOA's program requirements rather than as separate criteria.

Q23 – Can you provide a definition or range to clarify the phrase "commercially viable size"?
A23 – As stated in Q&A 6 above, the plant must be sized to produce at least 1 million ton/year of CO_2 that can be sequestered in a saline aquifer. Other than that, the applicant should show that the demonstration scale is such that it does not need to be demonstrated at a greater size to be ready for sale into the commercial market.

Q24 – When will the Power Point presentations used today be made available on either IPPS or NETL web page?
A24 – The Power Point Presentations are available at the following website:
http://www.netl.doe.gov/publications/proceedings/08/futuregen/index.html

Q25 – Please provide an explanation that states the similarities and differences between the Restructured FutureGen FOA and the CCPI FOA.
A25 – Both programs address the integration of power generation with CCS technology. However, FutureGen carries more stringent targets – 1 million metric tonnes/year in saline formation(s) [versus 300,000 tpy for CCPI-3, which may lend CCPI toward smaller demonstrations and is not limited to saline formation(s)], 81% CCS on all of the carbon in the syngas from a commercial-scale gasifier or flue gas from a boiler, and near zero emission targets (i.e., very low sulfur, NOx, particulate, & Hg emissions). The anticipated DOE funding levels are also very different – up to $1.3 billion for Restructured FutureGen versus up to $340 million for CCPI-3, depending upon Congressional appropriations.

Q26 – Please advise on the amount of funds currently appropriated for this FOA.
A26 - As stated in the FOA: "DOE anticipates approximately $290 million (through FY-09) will be available for incrementally funding project selection(s) under this FOA, and anticipates that an additional $1.01 billion may become available in subsequent years. Future fiscal year funding is subject to appropriations from Congress." Accordingly, it is our intention to select up to $1.3 billion (DOE share) worth of projects under this FOA.

Q27 – What is the amount that Congress has included for this program in the FY09 budget?
A27 – The Administration has requested $156M in FY09. The FY-09 Energy and Water Appropriation Bill has not yet been passed nor have the House and the Senate gone to conference on the FY-09 budget.

Q28 – Will DOE select projects and issue awards if there is insufficient funding for the selected projects?
A28 – DOE intends to select projects and issue awards based on an estimated total budget of $1.3 Billion which includes funds appropriated through the time of selection plus anticipated out-year appropriations.

Q29 – The FOA says on p12 that "since DOE is treating the costs (e.g. fuels) to produce electricity as an allowable cost…", "a separate charge for power supplied to the sequestration component will not be allowed, nor will…", "costs associated with reduced or lost opportunity"?
A29 –For greenfield projects, since the cost of producing power is included in the cost-sharing base, DOE will not recognize parasitic power cost as a separate cost to the project. For retrofits, the cost of producing the power is not in the cost-sharing base. Therefore, parasitic power for the retrofit components may be charged to the project at the cost of production versus lost-opportunity. See Q4 and Q17.

Q30 – Can we assume that even for a "bolt-on" retrofit, that the operating costs of the plant during the project are all "allowable"?
A30 – No. For a "bolt-on" retrofit, the baseline operating costs of the plant are not considered allowable. Additional operating costs necessitated by the retrofit are allowable and may be included in the incremental cost calculation.

Q31 – How and when will the decision regarding the type of award (Cooperative Agreement or TIA) be made?
A31 – The type of award instrument will be decided after selection during fact-finding and negotiations. DOE regulations describe the conditions where a TIA may be appropriate. See 10 CFR 600.603.110.

Q32 – To what degree will input from the proposer/selectee be considered?
A32 – After selection DOE will look at the project to determine if a TIA can be used and if it makes sense to use. Selectee input will be considered.

Q33 – Could we register in IIPS now?
A33 – Yes, applicants may register in IIPS now. However, it is more important to complete the www.Grants.gov registration NOW at www.grants.gov/GetStarted.

Applicants are reminded that IIPS (www.e-center.doe.gov) and www.Grants.gov are two separate and distinct systems. Applications must be submitted through www.Grants.gov and the registration process for this system could take up to 21 days.

Alternately, the IIPS website is for facilitating Questions and Answers on the Funding Opportunity and for posting updates. Also, once an application is submitted through www.Grants.gov, the Applicant will be able to view their application files in IIPS by logging into the system.